CANMET

Canada Centre for Mineral and Energy Technology

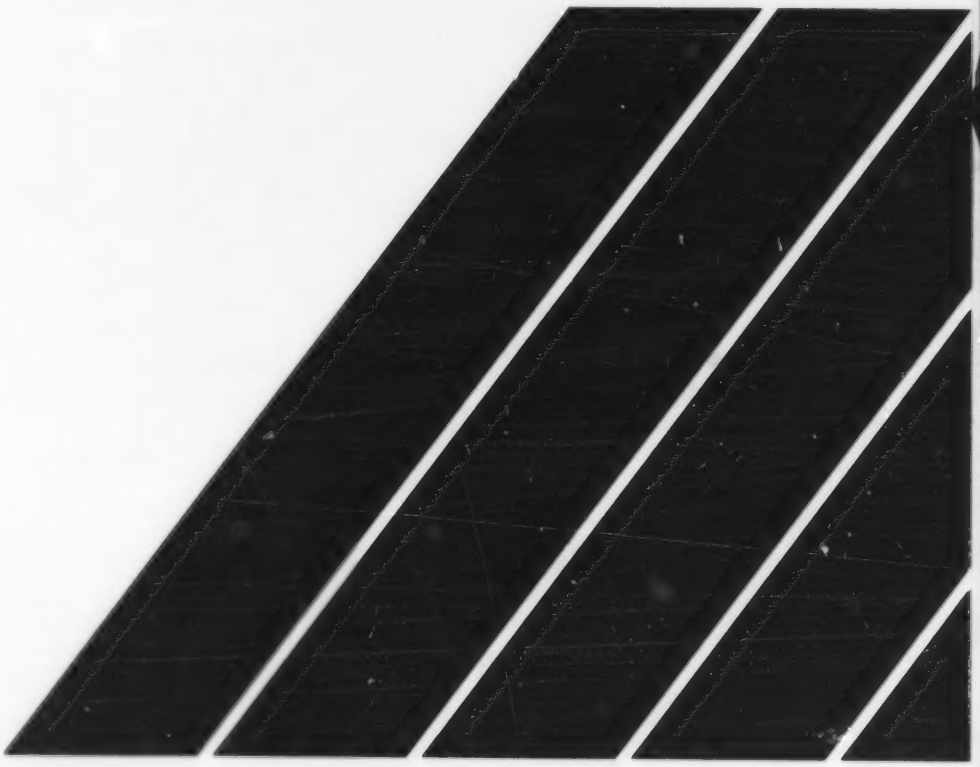
Centre canadien de la technologie des minéraux et de l'énergie

Energy Research Laboratories

Laboratoires de recherche sur l'énergie

RESULTS OF FIBEC TEST PROGRAM AT CANADIAN FORCES BASE HALIFAX DOCKYARD

January 1991



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RESULTS OF FIBEC TEST PROGRAM AT CANADIAN FORCES BASE HALIFAX DOCKYARD

January 1991

F.D. Friedrich and V.V. Razbin

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ABSTRACT

Results of FIBEC Test Program at Canadian Forces Base Halifax Dockyard

January 1991

F.D. Friedrich* and V.V. Razbin**

As part of the national management plan for NO_x control, Environment Canada has drafted emissions regulations for industrial boilers to encourage the use of best available technology economically achievable (BATEA). National Defence Canada, as a major boiler owner, has undertaken to demonstrate low-NO_x burners in two plants. One is fuelled by natural gas with No. 2 fuel oil backup and one is fuelled by Bunker C oil.

This report describes the results of combustion tests on the second demonstration - a package watertube boiler at CFB Halifax Dockyard which has been retrofitted with a heavy-oil burner employing flue gas recirculation (FGR) and a limited amount of air staging. Tests were conducted with No. 6 Bunker C oil, with and without FGR, over the load range of the boiler. Both efficiency and emissions were measured.

It was found that FGR has only a limited effect in reducing NO_x when firing No. 6 Bunker C oil. The draft regulations permit NO_x emissions of 110 ng/J, but the measured values typically exceeded this limit by about 50%. CO emissions were well below the limit and with a fuel sulphur content of about 2%, SO_2 emissions were close to double the allowable limit.

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RÉSUMÉ

Résultats du programme de mise à l'essai PRECIF
mené au chantier naval de Halifax
de la Base des Forces canadiennes

Janvier 1991

F.D. Friedrich* et V.V. Razbin**

Dans le cadre du programme national de gestion des émissions de NO_x, Environnement Canada a préparé un projet de règlement sur les émissions des chaudières industrielles afin d'encourager l'utilisation des meilleures techniques existantes d'application rentable (MTEAR). En qualité de grand propriétaire de chaudières, le ministère de la Défense nationale a entrepris la démonstration, dans deux usines, de brûleurs à faible dégagement de NO_x. Un de ces brûleurs est alimenté au gaz naturel et il utilise du fuel-oil lourd n° 2 comme combustible d'appoint; l'autre est alimenté au mazout de soutes de catégorie C.

Le présent rapport décrit les résultats d'essais de combustion menés sur la deuxième chaudière, soit une chaudière aquatubulaire préfabriquée au chantier naval de Halifax de la Base des Forces canadiennes. On y a ajouté un brûleur à mazout lourd dans lequel il y a recirculation des gaz de combustion et séparation limitée de l'air. Des essais ont été menés en utilisant du mazout de soutes de catégorie C, avec et sans recirculation des gaz de combustion, sur toute la gamme de charge de la chaudière. L'efficacité et les émissions y ont été mesurées.

La recirculation des gaz de combustion n'a qu'un effet limité sur la réduction des émissions de NO_x lorsque la chaudière est alimentée au mazout de soutes de catégorie C. En général, les émissions de NO_x dépassent d'environ 50 % la limite prévue dans le projet de règlement. Les émissions de CO sont bien en-dessous de la limite, tandis que celles de SO_2 atteignent presque deux fois la limite permise lorsque le combustible a une teneur en soufre d'environ 2 %.

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CONTENTS

	page
ABSTRACT	i
RESUME	ii
INTRODUCTION	1
DESCRIPTION OF PLANT	2
TEST PROGRAM	3
Objectives	3
Instrumentation	3
Test Conditions	4
Measurements and Calculations	7
RESULTS and DISCUSSION	7
Fuel Analyses	7
Boiler Efficiency	8
CO Emissions	8
NO_x Emissions	8
SO_2 Emissions	9
Effect of Excess Air on CO and NO_x	9
Emissions Tests on Boiler No. 4	10
CONCLUSIONS	11
ACKNOWLEDGEMENT	11

TABLES

1.	Fuel Analytical Data	12
2.	Average Raw Data	13
3.	Boiler Efficiency and Emissions	14
4.	Relationship among O_2, CO and NO_x	15
5.	Emission Data for Boiler No. 4	16

FIGURES

1.	Radiation and Convection Heat Loss	17
2.	Boiler Efficiency	18
3.	CO Emissions	19
4.	NO_x Emissions	20
5.	SO_2 Emissions	21
6.	Effect of Oxygen on NO_x Emissions	22
7.	Effect of CO on NO_x Emissions	23
8.	NO_x Emissions vs Load - Boiler No. 4	24

APPENDIX I — A-1

REGULATIONS RESPECTING RELEASE INTO THE AMBIENT AIR OF EMISSIONS FROM BOILERS AT FEDERAL FACILITIES

INTRODUCTION

Combustion source emissions of nitrogen oxides are viewed as a significant air pollution problem in Canada because they contribute to both acid rain and ground-level ozone. Accordingly, the Canadian Council of Ministers of the Environment has requested Environment Canada to develop a management plan for NO_x control. Furthermore, as a signatory to the international protocol for NO_x control, initiated by the United Nations Economic Commission for Europe, Canada is required to develop emission standards for combustion sources based on "best available technology economically achievable" to reduce by 1994 NO_x emissions to the 1987 level and to freeze them there.

Industrial boilers are believed to account for about 40% or 278 000 t/a of all stationary sources of NO_x emissions in Canada. Although the total inventory of federally-owned boilers of industrial size is believed to emit only a fraction of 1% of this figure (1100 t/a) it nonetheless comprises a large number of boilers, about 173, at 70 sites. Also, since emissions from federally-owned boilers fall under the jurisdiction of Environment Canada, they were deemed to be an appropriate group for which to develop new regulations which are expected to be adopted by provincial agencies and enforced on all industrial boilers.

New emission standards are being developed by the Federal Industrial Boiler Emission Control (FIBEC) Program. Through a task force involving burner and boiler manufacturers and federal departments which own boilers or otherwise have an interest, Environment Canada has attempted to determine the minimum emissions achievable by using the best technology which is economic and presently available for each of the common fossil fuels. Regulations have been drafted and are summarized in Appendix I. The draft regulations have been forwarded to the Privy Council Office and are expected to be published in Canada Gazette 1 in 1991.

National Defence Canada, as a major boiler owner and therefore a major stakeholder in the FIBEC program, has undertaken the demonstration of low NO_x combustion technologies in two of its heating plants at CFB St. Hubert near Montreal and CFB Halifax Dockyard. The St. Hubert plant's main fuel is natural gas with backup No. 2 fuel oil. The Dockyard plant's main fuel is No. 6 Bunker C with backup No. 2 fuel oil. One boiler in each plant has been retrofitted with an " advanced " burner employing flue gas recirculation (FGR) to reduce NO_x emissions.

This report describes tests on the retrofitted boiler at CFB Halifax Dockyard conducted by the Combustion and Carbonization Research Laboratory, Energy Research Laboratories, CANMET, as part of Energy, Mines and Resources Canada's contribution to the FIBEC program. Tests were performed with No. 6 Bunker C oil at four boiler loads to evaluate the effect of FGR on boiler efficiency and emissions particularly NO_x emissions.

DESCRIPTION OF PLANT

The central heating plant at CFB Halifax Dockyard contains five watertube boilers, all fired with heavy oil. Three of these are Vickers field-erected boilers, rated at 30,000 lb/h of steam at about 135 psig (13 600 kg/h at 932 kPa). They were originally equipped with coal stokers but were later converted to oil firing. Boiler No. 4 was installed in 1971. It is a 60,000 lb/h (27 500 kg/h) package watertube boiler built by Babcock and Wilcox, and equipped with a single steam-atomized oil burner. Boiler No. 5, another 60, 000 lb (27,500 kg/h) package watertube, was installed in 1986. Built by Versatile Vickers Inc., it was also oil-fired by a single burner and equipped with an economizer. It is a forced draft unit, having a forced draft fan but no induced draft fan and drawing combustion air from near the top of the boiler room. This was the boiler chosen for demonstration of low-NO_x technology.

Under the FIBEC program, the burner in Boiler No. 5 was replaced in late 1990 with a Faber burner marketed by Tampella Keeler. This is a register-type burner with a measure of air staging effected by secondary air nozzles which project about 20 cm beyond the oil nozzle. In addition, flue gas recirculation (FGR) is provided by a blower which can draw from either upstream or downstream of the economizer, and delivers to the burner windbox. The burner model is VP 26.5, having a maximum firing rate of 75 million Btu/h (22 MW_{th}) with No. 6 fuel oil. The new burner has its own management system, interfaced with the plant master. Boiler controls are fairly simple, with no monitoring of flue gas components.

TEST PROGRAM

OBJECTIVES

The primary objective was to measure the NO_x and SO_2 emissions from the boiler over the load range with the flue gas recirculation (FGR) system. Secondary objectives were to determine the boiler efficiency and the effect of FGR on emissions and on boiler efficiency.

INSTRUMENTATION

Flue gas was continuously analyzed for O_2, CO_2, CO, NO_x and SO_2 by an instrument package provided by the Combustion and Carbonization Research Laboratory (CCRL). This well-proven system comprises, besides the analyzers, a stainless-sinter stack probe with a heated line and a sample conditioning unit. The system extracts the sample from the stack, removes the moisture, which otherwise would contaminate the analyzer cells, and delivers dry flue gas at constant pressure, temperature and flow rate to the analyzers. The principle of operation, make and model of the analyzers are as follows:

O_2	Paramagnetic	Beckman Model 755
CO_2	Infrared	Horiba Model PIR 2000
CO	Infrared	Horiba Model PIR 2000
SO_2	Ultraviolet	Western Research Model 721A
NO_x	Chemiluminescent	Thermo Electron Model 10

The analyzers were calibrated usually at the beginning and end of each test by means of bottled span and zero gases. However, for the O_2 analyzer the span setting was obtained by using ambient air.

Combustion air temperature was obtained by installing a chrome-alumel thermocouple in the inlet duct to the forced draft fan. Flue gas temperature was monitored by two chrome-alumel thermocouples attached to the gas sample probe. One was located near the centreline of the breeching; the other was located 20 cm from the edge. The average flue gas temperature was calculated by assigning a weight of 2 to the centreline temperature, and a weight of 1 to the outer temperature.

Boilers 4 and 5 have rectangular breechings, fabricated in mild steel, which for some distance run horizontally, one above the other. The separation between them forms the roof of the breeching for Boiler No. 4 and the floor of the breeching for Boiler No. 5. Initially the stack sample probe with the stack temperature thermocouples was inserted through the top of the breeching for Boiler No. 5, in the portion concurrent with the breeching for Boiler No. 4. However, this produced some anomalous data; with Boiler No. 4 at high load and Boiler No. 5 at low load the stack temperature measured by the stack sample probe was higher than the economizer gas exit temperature for Boiler No. 5 as recorded in the control room. Then, when Boiler No. 4 tripped out because of a control problem, the stack temperature for Boiler No. 5 dropped, and the oxygen concentration increased. This strongly suggests leakage from one breaching into the other. To ensure valid results a new port for the stack sampling probe was installed at a point upstream from where the two breechings run together. Leakage in the breeching partition could well result from corrosion caused by acid condensation, which could occur when one boiler is running and the other is not.

Thermal output of the boiler was determined from the steam flow integrator on the control panel, which compared well with the average value obtained from the panel steam flowmeter. Flow was corrected to the orifice design pressure of 145 psig. Thermal input was available from an integrating oil flowmeter at the front of the boiler and was used to calculate boiler efficiency by the direct method for comparison with the results obtained by the indirect method. Other important data, such as flue gas and feedwater pressure and temperature at the inlet and outlet of the economizer, oil and atomizing steam conditions at the burner, steam pressure and burner/furnace pressures were obtained from plant instrumentation. Opacity of the stack emissions was determined by eye.

TEST CONDITIONS

Tests were carried out, with and without FGR, at load conditions approximating minimum fire (25%), 50, 75 and 100% of maximum capacity rating (MCR). Usually both air and fuel were under manual control. Typically a load condition would be set up and when steady state conditions had been established a test with FGR would be run for 2 h. Then, maintaining the same load conditions insofar as possible, a 1 or 2 h test would be carried out with the FGR blower turned off. A summary of observations for each test follows:

Test No. 1

Minimum fire with FGR
Duration: 2 h (January 15, 1445-1645 h)
The boiler had been at this load since early morning except for a brief shutdown to permit welding in a new port for the stack sample probe. The flame as seen from the front of the boiler was medium to bright yellow with clean edges. There were minor coke deposits on the diffusor. Viewed from the rear, the flame tips were soft yellow with very few sparklers (individual oil droplets burning beyond the flame envelope).

Test No. 2

Minimum fire without FGR
Duration: 2 h (January 15, 1715-1915 h)
Viewed from the front, the flame was very bright yellow. From the rear, the tails were somewhat longer than with FGR, and more clearly defined. As with FGR, there were very few sparklers.

Test No. 3

75% load with FGR
Duration: 2 h (January 16, 0845-1045 h)
Viewed from the front the flame was a fairly soft yellow. The diffusor was clean. Viewed from the rear, the flame had long feathery tails which required some burner adjustment to avoid impingement on the right-hand wall of the furnace. Burnout seemed to be complete with no sparklers.

Test No. 4

75% load without FGR
Duration: 1 h (January 16, 1115-1215 h)
Viewed from the front the flame was medium to bright yellow. Viewed from the rear the flame was somewhat larger than with FGR, and just touching the furnace walls. Flame tails were clean, with no smoke and no sparklers.

Test No. 5

Full load with FGR
Duration: 2 h (January 16, 1400-1600 h)
Viewed from the front the flame was soft to medium yellow and clean. Viewed from the rear, the flame washed along the furnace sidewalls and there were quite a few sparklers.

Test No. 6

Full load without FGR
Duration: 1 h (January 16, 1815-1915 h)
Viewed from the front the flame was a fairly bright yellow. The diffusor was clean. Viewed from the rear, the flame had clean, bright tails licking the furnace sidewalls, and there were some sparklers.

Test No. 7

50% load with FRG
Duration: 2 h (January 17, 0845-1045 h)
Viewed from the front the flame was medium to bright yellow and clean. The diffusor was clean. Viewed from the rear, the flame had bright, clean tails which tended to wash along the furnace sidewalls. Occasionally puffs of smoke were visible.

Test No. 8

50% load without FGR
Duration: 1 h (January 17, 1115-1215 h)
The flame was much the same as with FGR when viewed from the front. Viewed from the rear, however, the flame was longer than with FGR, having long, clean tails which constantly washed along the boiler sidewalls.

Some additional short-term tests were run on Boiler No. 5 to explore the relationships among excess air level, CO and NO_x. Emissions measurements were also carried out on Boiler No. 4 to check previous data obtained by Ortech International. Conditions and results of these supplementary tests are described separately.

MEASUREMENTS AND CALCULATIONS

Flue gas analysis and stack temperatures were electronically datalogged every 10 s, with average values computed and printed every 5 min. Information stored in the datalogger was subsequently fed into a computer which calculated average values for each test period. The additional data in Table 2 were manually logged every 15 min. from plant instrumentation and subsequently averaged for each test, in order to calculate boiler efficiency and emissions. The integrating meters for steam flow and oil flow were read at the start and end of each test.

Boiler efficiencies were calculated using the method specified in the ASME Test Form for Abbreviated Efficiency Test, PTC 4.1-a (1964). Efficiencies were calculated using both the direct and indirect methods. Radiation and convection losses from the boiler were estimated using the well known "Radiation and Convection Heat Loss Chart" published by the American Boiler Manufacturers' Association. From this was derived Fig. 1, which shows the relationship between load and radiation and convection losses for boilers similar to Boiler No. 5 at CFB Halifax Dockyard.

Table 2 records emissions as measured, i.e., ppm by dry basis volume in the actual flue gas. In Table 3 they are reported on the standardized basis of 3% O_2 in the flue gas and nanogram per joule (ng/J) of energy input as required by the proposed standard. The requisite calculations were carried out using the formulae specified by Environment Canada.

RESULTS AND DISCUSSION

FUEL ANALYSES

A sample of fuel oil was drawn from the primary oil heater on each day that testing was conducted, including January 18, 1991, the day that emissions measurements were conducted on Boiler No. 4. These samples were subsequently analyzed at the Energy Research Laboratories and the results are reported in Table 1. They are typical of No. 6 Bunker C fuel oil and furthermore are sufficiently consistent that an average analysis, also shown in Table 1, could be used for all the calculations.

BOILER EFFICIENCY

Boiler efficiencies determined by both the direct and indirect methods are reported in Table 3. They do not compare well; with one exception, the values obtained by the input/output (direct) method are 3 to 7% lower than those obtained by the heat loss (indirect) method. The values obtained by the indirect method are believed to be accurate within 0.5% in view of the accuracy with which flue gas analysis and flue gas temperature were measured. Therefore these are the values shown in Fig. 2. The errors in direct efficiency are probably due to inaccurate metering of fuel oil. For example, the oil meter is a volumetric device and no temperature correction factors were available. Errors of 10% or more are not uncommon in oil flowmeters of this type.

As shown in Fig. 2, boiler efficiency ranges from 86 to 88%, peaking at about 50% MCR. To establish the contribution of the economizer, losses were calculated using both the stack temperature and the economizer gas inlet temperature. The difference is reported in Table 3 as "efficiency gain due to economizer". This shows that the economizer increases boiler efficiency by about 3% at low load, and 7% at full load.

The data also suggest that FGR reduces boiler efficiency by about 0.2 to 0.6%, at least over most of the load range, despite the fact that excess air levels were somewhat higher in the tests without FGR. The explanation probably lies in the lower mass flow that prevailed without FGR, resulting in a lower stack temperature.

CO EMISSIONS

Average CO emissions for each test are shown in Fig. 3. As would be expected, the low values at minimum load correspond to relatively high levels of excess air. There is no discernible difference with or without FGR. In any case, the highest levels of CO, just under 20 ng/J, are well below the allowable limit of 125 ng/J.

NO_x EMISSIONS

As shown in Fig. 4, NO_x emissions at all loads are significantly above the allowable limit of 110 ng/J. FGR reduces NO_x by a modest amount ranging from about 3.5% at low load to 13.5% at full load. This effect may be as much

due to the higher excess air levels which prevailed when FGR was off as to the influence of FGR on flame temperature. Fortunately, emissions are lowest in the mid-load range, the range specified in the draft regulations for the measurements upon which the annual NO_x output of the boiler is based. Emissions of NO_x are higher at low load, probably because of the higher excess air level. They are also higher at full load probably because the flame fills the furnace, providing a longer residence time in the temperature regime which favours NO_x formation.

SO_2 EMISSIONS

With a fuel sulphur content of more than 2%, it is not surprising that the SO_2 emissions shown in Fig. 5 are nearly double the allowable limit of 500 ng/J. What is surprising, however, is that the tests with FGR consistently show higher SO_2 emissions by amounts ranging from 1.5 to 7.7% than the tests without FGR. An explanation for this is not obvious.

EFFECT OF EXCESS AIR ON CO AND NO_x

It is generally known that reducing excess air levels tends to reduce NO_x emissions. This is partly because NO formation is reduced by the lower availability of O_2, but also because reducing the level of excess air tends to reduce the peak flame temperature. In addition, lower excess air levels may result in higher levels of CO, which acts as a reductant to convert NO to CO_2 and N_2. To determine whether this offered any potential for reducing NO_x emissions from Boiler No. 5, some additional testing was carried out.

Upon completion of Test 5, the full-load test with FGR, excess air was reduced by partially closing the inner air register, which also increased swirl. The level of O_2 in the flue gas was decreased from about 3% to about 1.8%. Corresponding levels of CO and NO_x were recorded for about 40 min with the results shown in Table 4, Test 5A. NO_x emissions were reduced by about 10 ppm, when calculated to the normalized basis of 3% O_2. Normalized concentrations of CO fluctuated from about 30 to 130 ppm, with no apparent pattern.

The FGR fan was then turned off and the data in Table 4, Test 5B were recorded. It is noteworthy that O_2 increased by nearly 0.5%, presumably due to reduced pressure drop at the windbox. CO increased to unacceptable levels, sometimes approaching 1000 ppm, but NO_x emissions dropped by an average of

another 20 ppm, again on the normalized basis. This was the only test in which visible smoke was observed at the stack. The test was terminated when the boiler tripped because of unrelated causes.

Following Test 6, the full-load test without FGR, Test 6A was carried out, in which O_2 in the flue gas was progressively reduced from 3.5 to 1.6% over 45 min. These results are also presented in Table 4. There is no discernible trend in either CO or NO_x emissions. There were a few occasions, not recorded in the 5 min averages, when CO rose suddenly to 400 or 500 ppm, but then dropped back just as suddenly to less than 100 ppm. A possible explanation is that coke whiskers formed on the burner nozzle and interfered with atomization, then broke off.

The results given in Table 4 are plotted in Fig. 5 and 6. These show that reducing excess air does indeed reduce NO_x, but with results scattered over a wide band. It can also be seen that NO_x decreases as CO increases. The effect is most noticeable at low levels of CO emissions and achieves a NO_x reduction of 20 to 30 ppm but still doesn't meet the guidelines.

EMISSIONS TESTS ON BOILER No. 4

Boiler No. 4 is a watertube package built by Babcock and Wilcox. It is similar in design to Boiler No. 5 and has the same rated capacity. However, it was installed in 1971, and is still equipped with the original steam-atomized oil burner with no FGR. On January 18, 1991, emissions tests were carried out on this boiler, partly to check measurements obtained previously by Ortech International, and partly to explore further the influence of excess air on NO_x emissions. The results are presented in Table 5 and Fig. 8.

At 90% MCR, excess air was reduced stepwise from 4% O_2 to 2.5% O_2, and NO_x emissions dropped by more than 30 ppm, a reduction similar to that experienced on Boiler No. 5. Surprisingly, the reduction in excess air resulted in a drop rather than an increase in CO. The CANMET results essentially confirm the Ortech results, considering the possibility of variations in fuel nitrogen content.

It is noteworthy that on Boiler No. 4, NO_x emissions continued to drop as load was decreased and would appear to meet the draft regulations at 30% MCR or less. With Boiler No. 5, NO_x emissions reached a minimum at about 50% load, and increased sharply as load was increased or decreased.

CONCLUSIONS

1. Efficiency of Boiler No. 5 is high, up to 88%, and fairly flat, varying by less than 2% over the load range. Flue gas recirculation appears to impose a modest penalty on efficiency. The economizer makes an important contribution to efficiency, ranging from about 3.2% at low load to 7.2% at full load.

2. During the formal tests on Boiler No. 5, CO emissions were always well below the allowable limit of 125 ng/J, with no relationship to the presence or absence of FGR. However, in separate tests to explore the effects of excess air on NO_x, levels of CO were unacceptably high at times, when there was no FGR.

3. NO_x emissions from Boiler No. 5 are significantly above the allowable limit of 110 ng/J at all loads, but are lowest at about 50% MCR. FGR reduces NO_x by a modest amount, from about 3.5% at low load to 13.5% at full load. It was found that NO_x could be reduced by 20 to 30 ppm by reducing O_2 in the flue gas to less than 2%, but at some risk of exceeding the allowable limit for CO.

4. SO_2 emissions are nearly double the allowable limit of 500 ng/J. Compliance, without resorting to flue gas scrubbing, would require a reduction in fuel sulphur content to about 1%.

5. In terms of NO_x emissions, Boiler No. 4, with a conventional burner and no FGR, performed as well as Boiler No. 5 at high loads, and better at low loads. This indicates that for industrial boilers fired with heavy fuel oil, available strategies for NOx reduction are largely unproven, particularly in retrofit situations. Further R&D is required.

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Table 1 - Fuel analytical data

Sample Date, 1991	Jan 15	Jan 16	Jan 17	Jan 18	Avg.
Ultimate Analysis					
Carbon (C)	86.3	86.6	86.6	86.9	86.71
Hydrogen (H_2)	10.9	10.8	10.7	10.7	10.78
Nitrogen (N_2)	0.43	0.44	0.41	0.43	0.43
Sulphur (S)	2.12	2.11	2.07	2.02	2.08
HHV, Btu/lb	18,362	18,332	18,416	18,336	18,360
Specific gravity (relative to water at 60/60 ^{0}F)	0.990	0.989	0.991	0.991	0.990

Table 2 - Average raw data

Test No.	1	2	3	4	5	6	7	8
FGR - on / off	on	off	on	off	on	off	on	off
Steam output, 1000 lb/h 1)	16.0	16.3	44.1	44.7	58.8	58.0	29.4	29.4
Steam pressure, psig	134.1	133.9	139.2	139.0	140.4	139.8	136.6	136.6
Economizer data								
Feedwater temperature in, deg C	112.4	113.0	113.0	113.0	113.0	113.0	113.0	113.0
Feedwater pressure in, psig	129.0	128.6	137.4	137.7	141.8	141.0	141.0	133.7
Feedwater temperature out, deg C	127.7	126.0	144.2	136.7	148.4	145.7	145.7	128.0
Feedwater pressure out, psig	125.8	126.2	134.7	135.3	137.6	138.0	138.0	131.0
Flue gas temperature in, deg C	222.8	222.0	328.0	310.0	372.0	370.8	264.4	252.8
Flue gas temperature out, deg C	134.0	134.0	172.0	160.0	189.8	184.4	143.6	140.8
Heavy fuel oil flow rate, L/h	497.5	455.0	1345.0	1360.0	1815.0	1780.0	865.0	855.0
Fuel oil pressure, psig	25.3	25.4	63.1	63.6	77.8	77.6	46.1	46.4
Fuel oil temperature, deg C	91.8	91.6	95.5	95.7	95.6	95.2	94.9	95.6
Atomizing steam pressure, psig	40.0	40.0	75.4	76.0	85.9	85.6	60.4	60.7
Burner windbox pressure, mm water	2	1	85	60	160	130	20	15
Furnace pressure, mm water	-1	-1	50	30	90	79	6	1
Economizer outlet pressure, mm water	-6	-6	-6	-5	-5	1	-11	-12
Flue gas stack temperature, deg C	148.7	148.3	193.1	175.2	211.4	202.6	160.0	154.1
Combustion air temperature, deg C	34.2	33.6	35.9	35.3	33.3	35.7	34.5	34.0
Flue gas analysis								
Oxygen, %	5.59	5.61	2.01	2.29	2.95	3.49	1.84	2.02
Carbon dioxide, %	13.30	12.46	14.76	14.52	13.84	13.41	14.17	14.17
Carbon monoxide, ppmv measured	14	9	39	52	58	32	61	40
Nitrogen oxides, ppmv measured	259	269	262	271	279	313	266	279
Sulphur dioxide, ppmv measured	1006	965	1203	1168	1195	1069	1270	1191

1. Corrected to orifice calibration pressure of 145 psig

Table 3 Boiler efficiency and emissions

Test No.	1	2	3	4	5	6	7	8
FGR - on / off	on	off	on	off	on	off	on	off
Steam output, % MCR	26.7	27.2	73.5	74.5	98.0	96.7	49.0	49.0
Heat absorbed, 10^6 BTU/h	15.86	16.14	43.70	44.29	58.27	57.47	29.12	29.12
Heat input, 10^6 BTU/h	19.94	18.23	53.90	54.50	72.73	71.33	34.66	34.26
Excess air, % 1)	34.58	34.28	9.90	11.44	15.23	18.57	8.90	9.87
Dry flue gas, lb/lb of fuel fired 2)	16.62	17.66	15.02	15.25	15.96	16.44	15.59	15.60
Boiler efficiency - direct method, %	79.54	88.54	81.08	81.27	80.12	80.57	84.02	85.00
Boiler efficiency - indirect method								
Dry flue gas loss, % 2)	4.48	4.77	5.56	5.02	6.69	6.46	4.60	4.41
Hydrogen loss, % 2)	5.99	6.00	6.17	6.10	6.28	6.21	6.04	6.02
Radiation and convection loss, % 3)	2.25	2.22	0.91	0.89	0.63	0.65	1.30	1.30
Unmeasured losses, % 4)	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Total losses, %	12.97	13.24	12.89	12.26	13.85	13.57	12.19	11.98
Efficiency - indirect method, %	87.03	86.76	87.11	87.74	86.15	86.43	87.81	88.02
Efficiency gain due to economizer, %	3.19	3.38	5.36	5.19	6.75	7.26	4.29	4.05
Flue gas emissions - calculated								
Carbon monoxide, ppmv at 3% O_2	17	10	37	46	58	34	57	38
Carbon monoxide, ng/J	5.7	3.4	12.5	15.5	19.5	11.4	19.2	12.8
Nitrogen oxides, ppmv at 3% O_2	304	315	249	262	279	322	251	265
Nitrogen oxides, ng/J	168.2	174.2	137.7	144.9	154.3	178.1	138.8	146.6
Sulphur dioxide, ppmv at 3% O_2	1179	1132	1143	1126	1193	1108	1196	1129
Sulphur dioxide, ng/J	908.8	872.6	881.1	868.0	919.6	854.1	921.9	870.3

1) Calculated from O_2 analysis
2) Calculated according to ASME test procedure
3) From Fig. 1
4) An assumed value to cover minor losses

Table 4 Relationship among O_2, CO and NO_x

Time/Date Jan16, 1991	O_2, %	CO, ppm measured	NO_x, ppm measured	CO, ppm normalized to 3 % O_2	NO_x, ppm normalized to 3% O_2
	Test 5A. Full load with FGR				
16:20	1.8	51	284	48	267
16:25	1.6	39	291	36	270
16:30	1.8	34	294	31	275
16:35	1.7	38	290	35	272
16:40	1.8	54	284	51	266
16:45	1.8	78	280	73	263
16:50	1.8	138	274	129	256
16:55	1.8	57	289	54	272
17:00	1.7	35	292	33	273
17:05	1.8	33	295	31	275
	Test 5B. Full load without FGR				
17:10	2.2	369	268	344	250
17:15	2.3	432	265	418	256
17:20	2.2	559	264	538	254
17:25	2.2	589	262	567	252
17:30	2.2	508	259	487	248
17:35	2.0	860	258	819	245
17:40	2.1	1021	257	972	244
17:45	2.1	976	260	926	248
	Test 6A. Full load without FGR				
19:15	3.4	39	293	40	300
19:20	3.5	65	282	67	290
19:25	2.8	426	275	421	272
19:30	2.6	30	324	30	319
19:35	2.1	34	323	32	307
19:40	1.7	61	318	57	296
19:45	1.6	149	312	138	290
19:50	1.5	123	314	115	292
19:55	1.6	63	318	58	294
20:00	1.6	68	318	63	295

Table 5 Emissions data for Boiler No. 4

Flue gas analysis						
	As measured		Normalized to 3% O_2			NO_x
Time	O_2,%	CO_2%	CO, ppm	NO_x,ppm	SO_2,ppm	ng/J
75% MCR						
09:45	4.3	13.2	40	262	1055	145
09:50	4.2	13.2	41	287	1072	159
09:55	4.0	13.3	41	263	1063	146
90% MCR						
10:10	3.9	13.3	53	319	1072	176
10:15	4.0	13.3	53	321	1060	178
10:20	4.0	13.3	53	318	1059	176
Reduced O_2						
10:35	3.6	13.6	48	327	1068	181
10:40	3.5	13.6	49	314	1066	174
10:45	3.4	13.7	47	302	1070	167
10:50	3.6	13.6	47	311	1060	172
Reduced O_2						
11:00	2.8	14.2	42	295	1087	163
11:05	2.8	14.3	42	295	1087	163
11:10	2.6	14.2	45	268	1070	148
11:15	2.5	14.3	40	284	1069	157
40% MCR						
11:55	2.3	14.5	47	208	1033	115
12:00	2.3	14.6	56	205	1034	113
12:05	2.3	14.6	64	207	1033	114
12:10	2.3	14.5	53	208	1031	115
12:15	2.3	14.6	60	196	1022	108
12:20	2.2	14.6	50	209	1020	115
12:25	2.2	14.6	68	197	1017	109

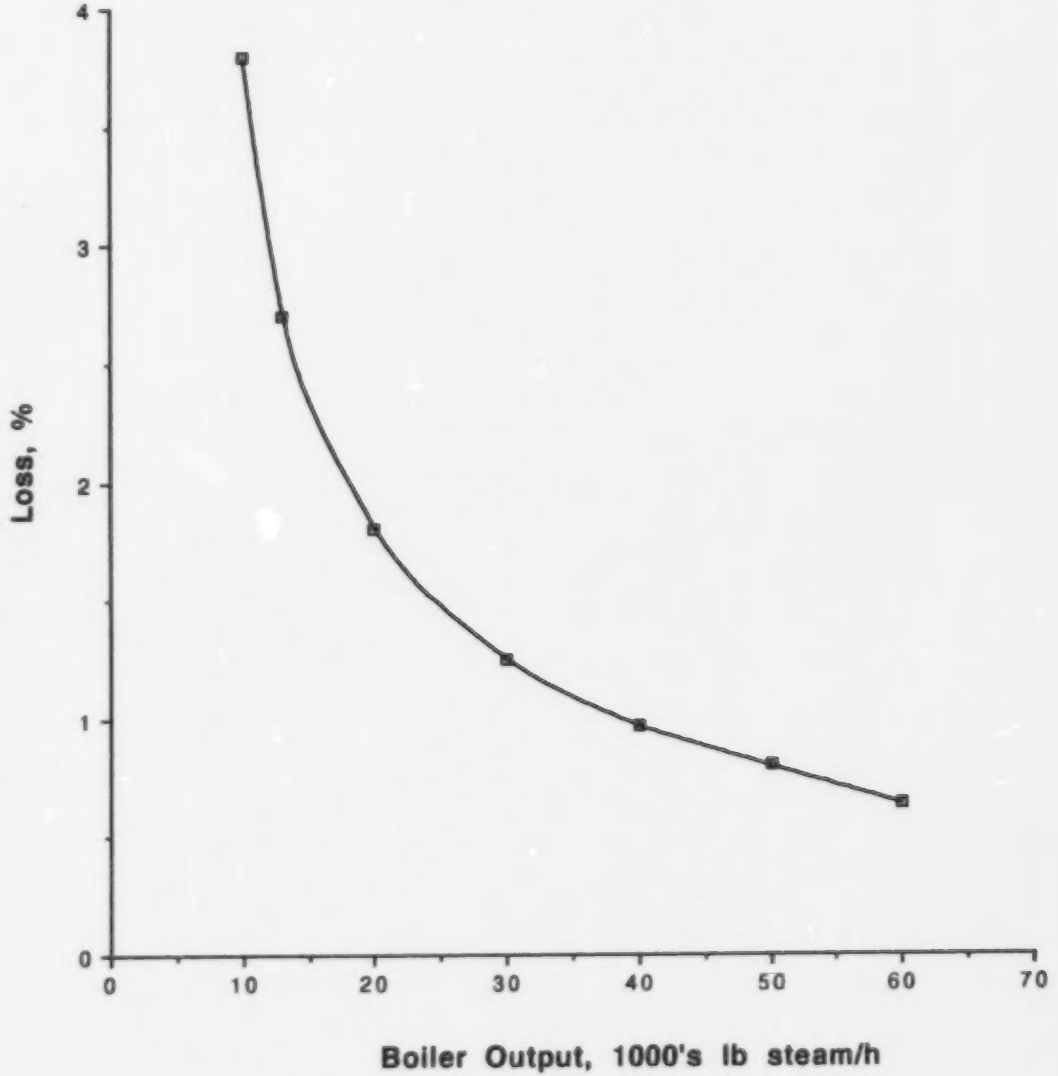

Fig. 1 Radiation and convection heat loss

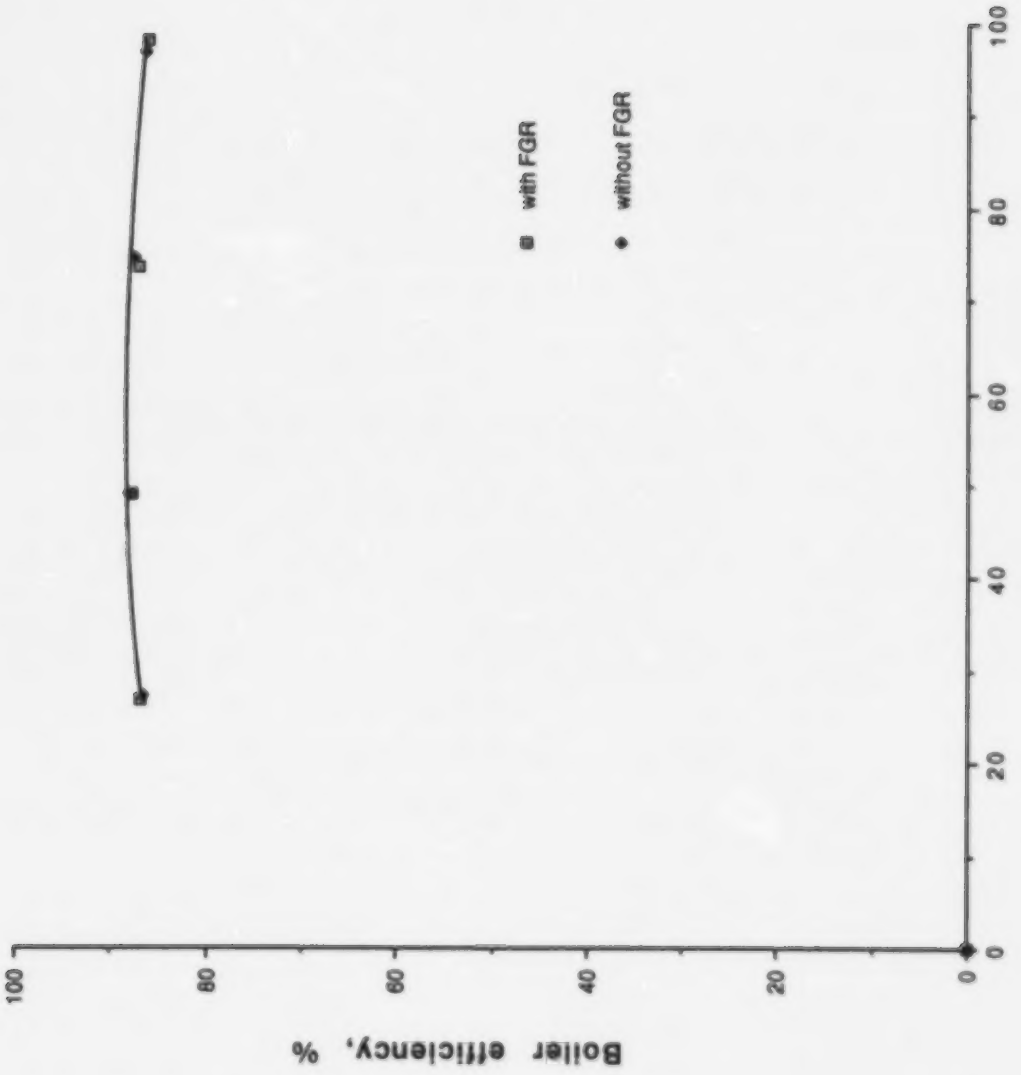

Fig. 2 Boiler efficiency

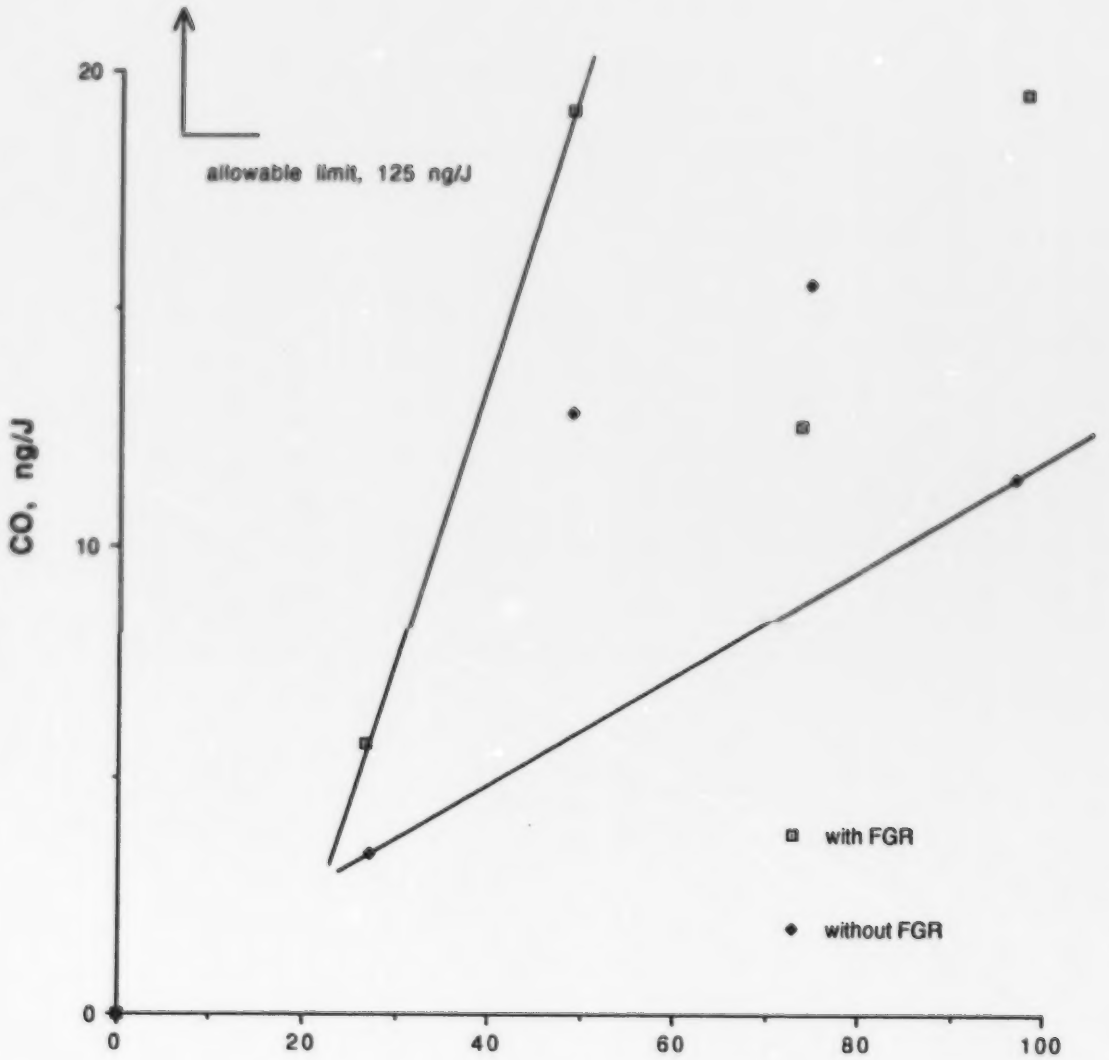

Fig. 3 CO emissions

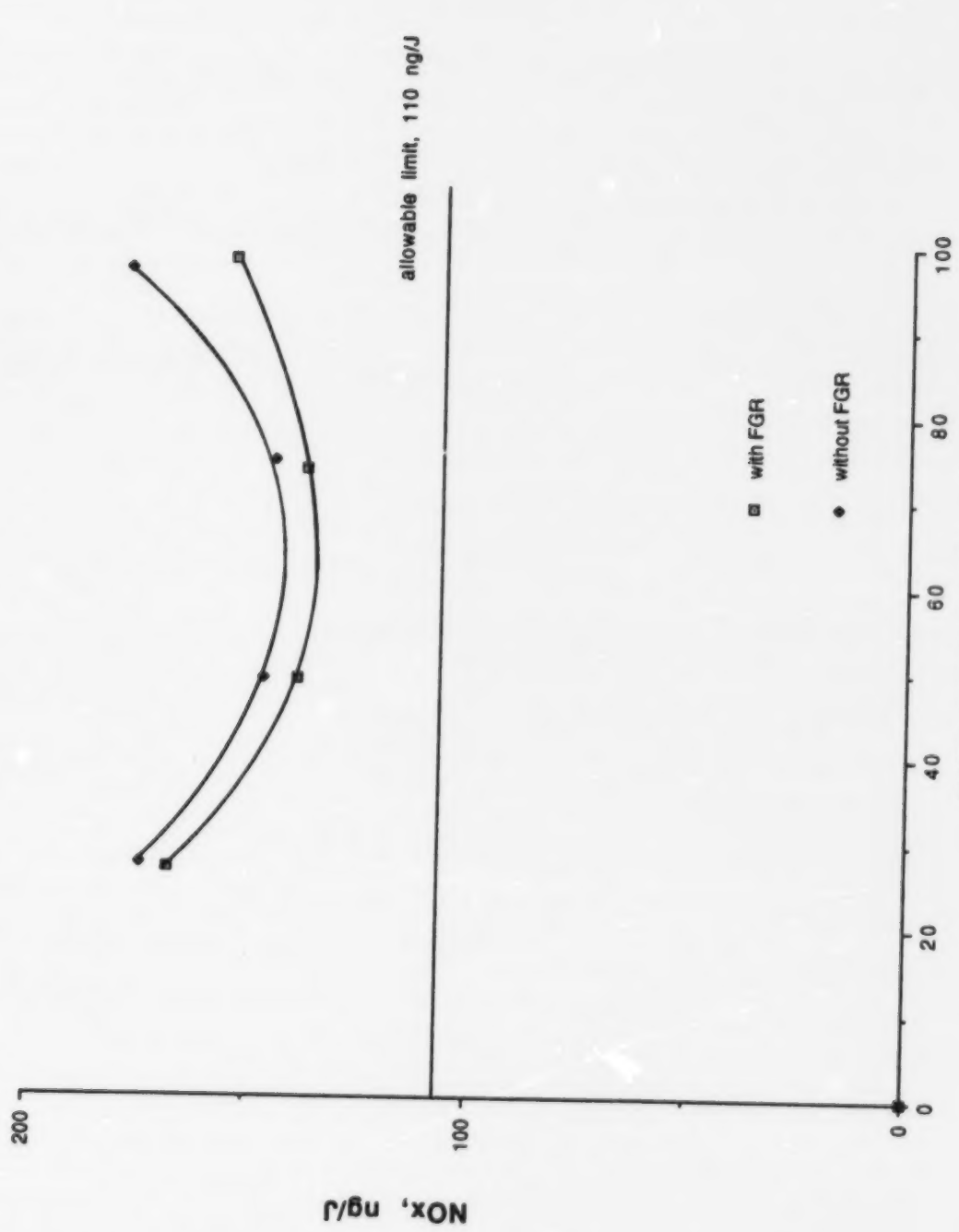

Fig. 4 NOx emissions

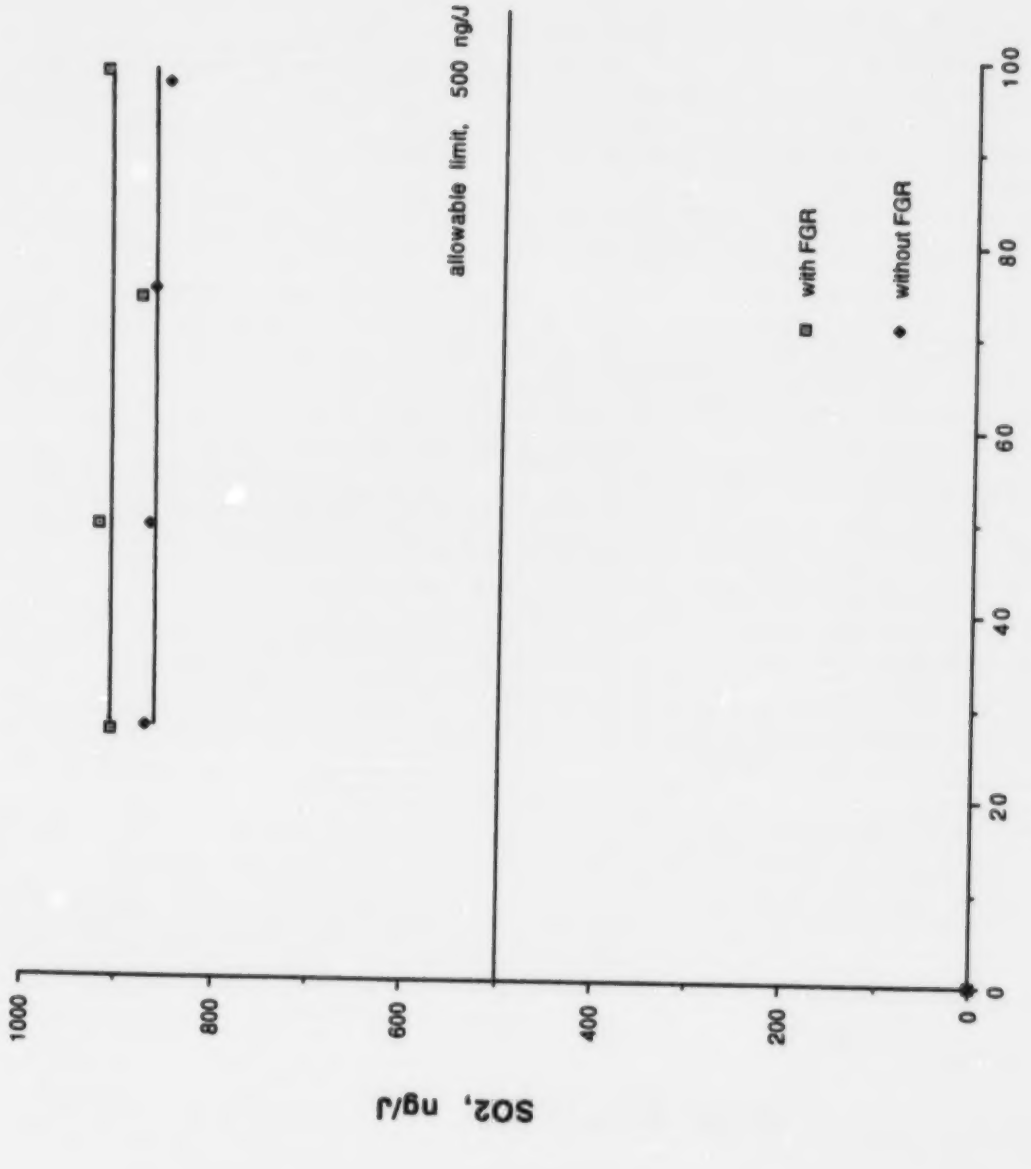

Fig. 5 SO2 emissions

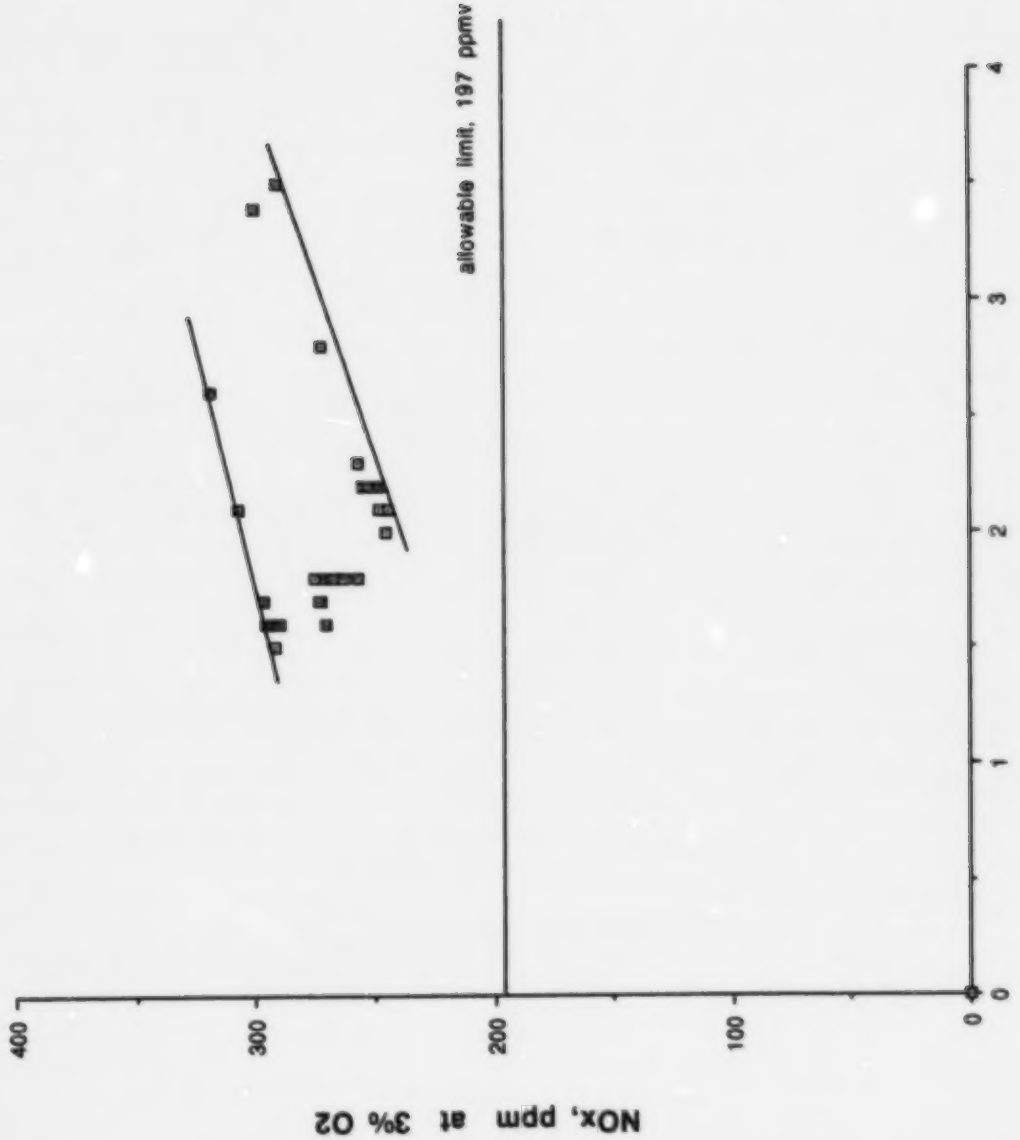

Fig. 6 Effect of oxygen on NOx emissions

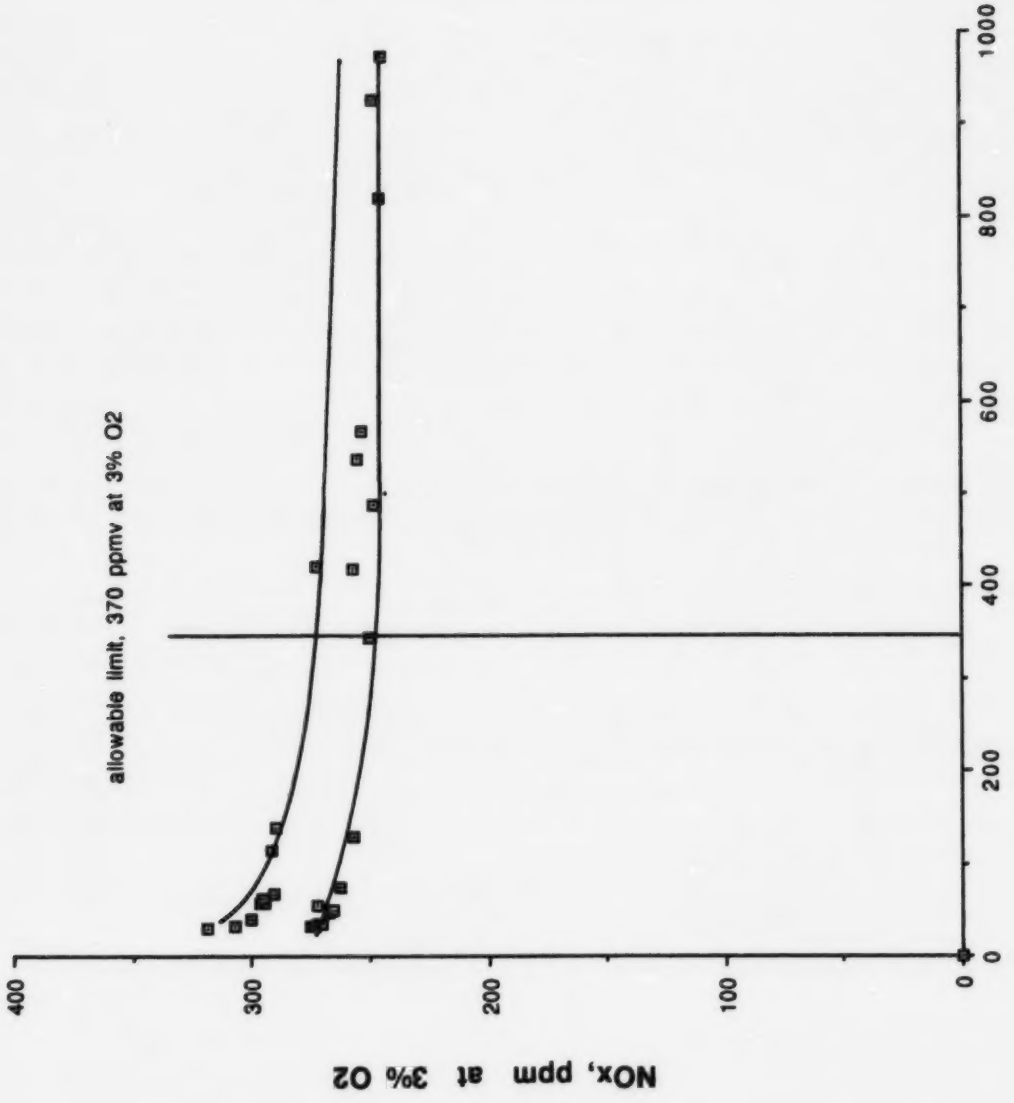

Fig. 7 Effect of CO on NOx emissions

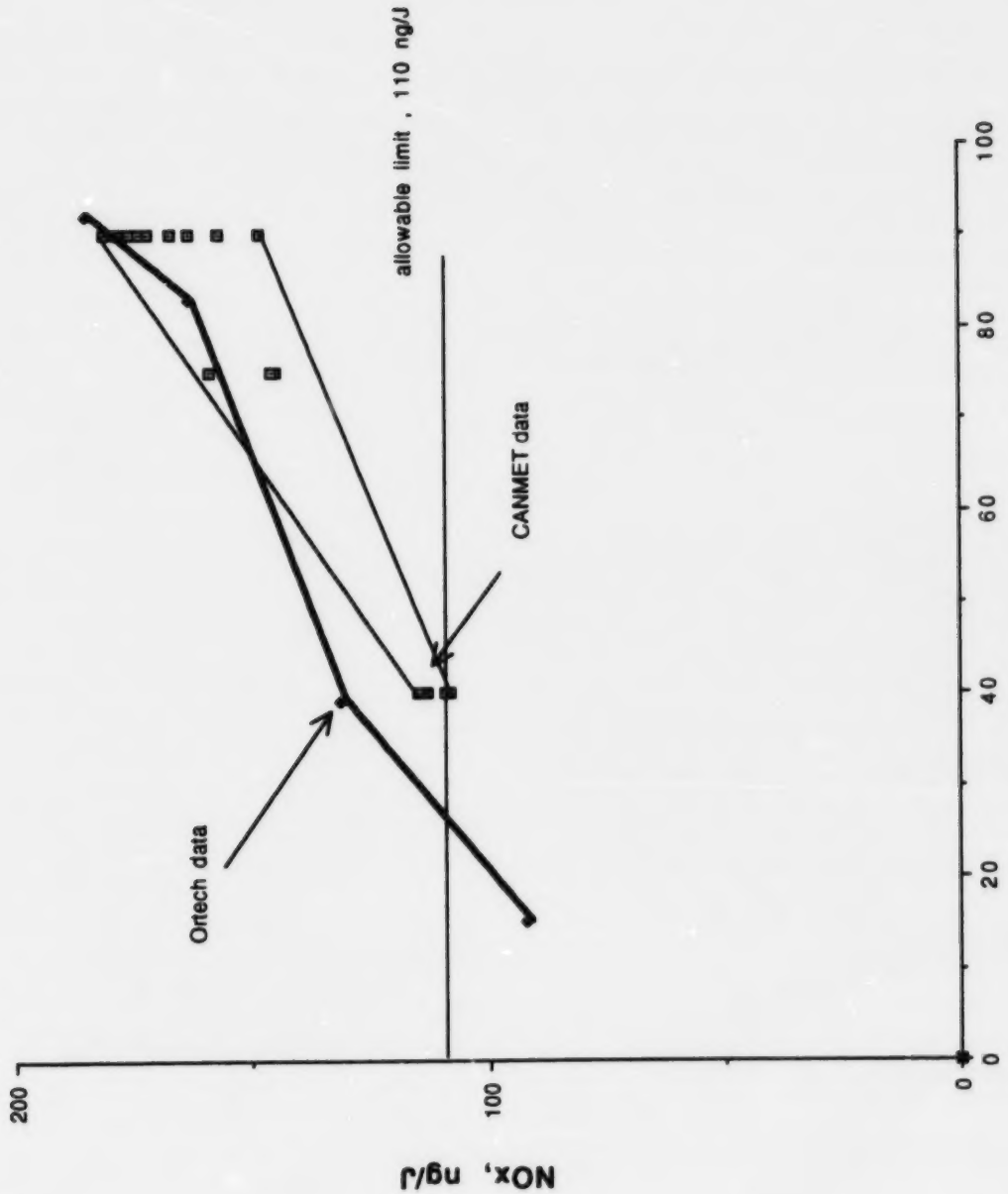

Fig. 8 NOx emissions vs load - Boiler No. 4

APPENDIX I

REGULATIONS RESPECTING RELEASE INTO THE AMBIENT AIR OF EMISSIONS FROM BOILERS AT FEDERAL FACILITIES*

Short Title

1. These Regulations may be cited as the Federal Boiler Emission Regulations.

Interpretation

2. In these Regulations,

"boiler" means a device that burns fossil fuel for the purpose of generating hot water or steam and is used primarily for the heating of buildings: (chaudiere)

"new boiler" means a boiler for which a contract to purchase is signed on or after April 1, 1991; (chaudiere existante)

"federal institution" means a department, board or agency of the Government of Canada, or any corporation that is named in Schedule III to the Financial Administration Act; (institution federale)

"fossil fuel" means natural gas, petroleum, coal, and any form of gaseous, liquid or solid fuel derived from such for the purpose of creating useful heat; (combustible fossile)

"MJ/s" means megajoules per second; (MJ/s)

"mg/m^3" means milligram per cubic metre on a dry basis at 298 K and 101.3 kPa; (mg/m^3)

"ng/J" means nanograms per joule; (ng/J)

* Draft; October 1990

"solid fossil fuel" means coal, or any combination of fuels for which coal is the primary source of usable energy; (combustible fossile solide)
"gaseous fossil fuel" means natural gas or propane or any fuel in the gaseous state derived from natural gas or propane; (combustible fossile gazeux)

"nitrogen oxides" means all oxides of nitrogen except nitrous oxide, collectively expressed as nitrogen dioxide; (oxydes d'azote)

"undiluted" means in a condition that does not include air or other gases in excess of the quantity necessary for the normal operating requirement of the boiler; (non-dilue)

"smoke density" means the smoke density of a flue gas determined in accordance with the American Society for Testing and Materials (ASTM) designation D 2156-80, reapproved 1988; (densite de la fumee)

"CGSB classification" means the classification of fuel types specified in "National Standard of Canada CAN2-3.2-M81 Fuel Oil, Heating" published by the Canadian General Standards Board, as amended from time to time. (classification de l'ONGC)

Application

3. These Regulations apply in respect of facilities owned or operated by a federal institution.

Duty of Federal Institutions

4. Where a boiler is operated under contract with a federal institution, the federal institution shall ensure that the person who operates the boiler complies with sections 5 to 13.

Prohibition

5. No person shall operate a boiler except in accordance with sections 6 to 13.

Emissions Standards for New Boilers

6. The rate of discharge of air contaminants from a new boiler having a heat input capacity greater than 1.5 MJ/s and less than 50 MJ/s shall not exceed:

a) for nitrogen oxides expressed as nitrogen dioxide:

i) 150 ng/J of heat input when fired with solid fossil fuel,

ii) 110 ng/J of heat input when fired with oil specified as type 4, 5 or 6, according to CGSB classification,

iii) 43 ng/J of heat input when fired with oil specified as type 1 or 2, according to CGSB classification, and

iv) 22 ng/J of heat input when fired with gaseous fuel;

b) for sulphur dioxide:

i) 500 ng/J of heat input when fired with solid fossil fuel,

ii) 500 ng/J of heat input when fired with oil specified as type 4, 5 or 6, according to CGSB classification, and

iii) 25 ng/J of heat input when fired with oil specified as type 1 or 2, according to CGSB classification;

c) for particulate matter measured undiluted, 160 mg/m^3, when fired with solid fossil fuel; and

d) for carbon monoxide, 125 ng/J of heat input.

Emissions Standards for Existing Boilers

7. 1) Subject to Section 9, effective April 1, 1997, the rate of discharge of nitrogen oxides, expressed as nitrogen dioxide, from an existing boiler having a heat input capacity greater than 5.9 MJ/s and less than 50 MJ/s, shall not exceed

a) 150 ng/J of heat input when fired with solid fossil fuel

b) 110 ng/J of heat input when fired with oil specified as type 4, 5 or 6, according to CGSB classification

c) 43 ng/J of heat input when fired with oil specified as type 1 or 2, according to CGSB classification, and

d) 22 ng/J of heat input when fired with gaseous fuel.

2) Effective April 1, 1994, the rate of discharge of air contaminants from an existing boiler having a heat input capacity greater than 5.9 MJ/s and less than 50 MJ/s shall not exceed

a) for sulphur dioxide;

i) 500 ng/J of heat input when fired with solid fossil fuel,

ii) 500 ng/J of heat input when fired with oil specified as type 4, 5 or 6, according to CGSB classification, and

iii) 25 ng/J of heat input when fired with oil specified as type 1 or 2, according to CGSB classification;

b) for particulate matter measured undiluted, 160 mg/m^3, when fired with solid fossil fuel;

c) for carbon monoxide, 125 ng/J of heat input.

3) Subsection (1) does not apply to an existing boiler that is part of a facility described in column I of an item of Schedule I or II, where notice is received by the Minister pursuant to subsection 9 (1) or (3).

Revision of Base Year NO_x Emission

8. 1) For the purposes of this section and section 9

a) "base year NO_x emission" of nitrogen oxides means for

i) a facility listed in column I of an item of Schedule I, the total emission, in tonnes, set out in column III of the item, and

ii) a facility listed in column I of an item of Schedule II, the total emission, in tonnes, set out in column III of that item;

b) "responsible federal department or institution" means, with respect to a facility, the federal department or institution specified in column II of an item of Schedule I or II, for the facility specified in column I of that item.

2) Where the responsible federal department or institution requests that the Minister review the base year NO_x emission for a facility, the Minister shall review the base year NO_x emission based on information provided pursuant to the subsection (3)

3) Where a federal department or institution makes a request with respect to a facility pursuant to subsection (2), the department or institution shall provide the Minister, prior to June 1 of any year, with the information required pursuant to Schedules IV and V for the period from April 1 of the preceding year to March 31 of that year for that facility.

4) The Minister shall revise the base year NO_x emission for a facility where he is satisfied that such a revision is justified based on the information provided pursuant to subsection (3) and any other information relevant to the control of emissions from that facility.

Reduction of Total Emissions From Existing Boiler Facilities

9. 1) Where an existing boiler having a heat input capacity greater than 5.9 MJ/s and less than 50 MJ/s is part of a facility described in column I of an item of Schedule I, the responsible federal department or institution shall, after giving written notice to the Minister prior to June 1, 1994, reduce nitrogen oxides emissions from all boilers comprising the facility, in accordance with subsection (2).

2) For the purposes of subsection (1), emissions of nitrogen oxides from all boilers comprising the facility shall be reduced by:

a) in the twelve month period commencing April 1, 1995 and ending March 31, 1996, for a facility referred to in Column I of an item of Schedule I, 25 percent of the amount set out in Column III of that item and,

b) in the twelve month period commencing April 1, 1997 and ending March 31, 1998, and in any subsequent twelve month period commencing April 1 and ending March 31, for a facility referred to in Column I of an item of Schedule I, 50 percent of the amount set out in Column III of that item.

3) Where an existing boiler having a heat input capacity greater than 5.9 MJ/s and less than 50 MJ/s is part of a facility described in column I of an item of Schedule II, the responsible federal department or institution shall, after giving written notice to the Minister prior to June 1, 1994, reduce nitrogen oxides emissions from all boilers comprising the facility, in accordance with subsection (4)

4) For the purposes of subsection (3) emissions of nitrogen oxides from all boilers comprising the facility shall be reduced by:

a) in the twelve month period commencing April 1, 1995 and ending March 31, 1996, for a facility referred to in Column I of an item of Schedule II, fifteen percent of the amount set out in Column III of that item; and,

b) in the twelve month period commencing April 1, 1997 and ending March 31, 1998, and in any subsequent twelve month period commencing April 1 and ending March 31, for a facility referred to in Column I of an item of Schedule II, thirty percent of the amount set out in Column III of that item.

5) For the purposes of subsections (2) and (4) emissions of nitrogen oxides for any twelve moth period shall be determined in accordance with Schedule V.

Smoke Density

10. A new boiler having a heat input capacity greater than 1.5 MJ/s and less than 50 MJ/s, and an existing boiler having a heat input capacity greater than 5.9 MJ/s and less than 50 MJ/s shall be operated in such a manner that the smoke density of the flue gases does not exceed

a) a smoke spot number of 5, when fired with oil specified as type 4, 5 or 6, according to CGSB classification; and

b) a smoke spot number of 3, when fired with oil specified as type 1 or 2, according to CGSB classification.

Emissions Testing

11. 1) For the purposes of sections 5 to 10, emissions testing shall be conducted by the operator at least once per year on the date and at the location specified in a written notice received by the Minister no less than 30 days in advance of the day on which the testing is to be conducted.

2) The notice referred to in subsection (1) shall specify the reference methods and test procedures to be used.

3) Where requested by the Minister, emissions testing shall be conducted in the presence of an inspector.

4) An emissions test required under subsection (1) shall be conducted using the following test methods:

a) for nitrogen oxides the reference method specified in the Department of the Environment Report EPS 1/RM/15, "Reference Method for the Monitoring of Gaseous Emissions from Fossil-Fuel Fired Boilers", as amended from time to time;

b) for particulate matter, the reference method specified in the Department of the Environment Report EPS 1-AP-74-1, "Standard Reference Methods for Source Testing: Measurement of Emissions of Particulates from Stationary Sources", as amended from time to time;

c) for sulphur dioxide, the reference method specified in the Department of the Environment Report EPS 1/RM/15, "Reference Method for the Monitoring of Gaseous Emissions from Fossil-fuel Fired Boilers", as amended from time to time;

d) for carbon monoxide, the reference method specified in the Department of the Environment Report EPS 1/RM/15, "Reference Method for the Monitoring of Gaseous Emissions from Fossil-Fuel Fired Boilers", as amended from time to time; and

e) for smoke density, in accordance with the American Society for Testing and Materials (ASTM) Designation D 2156-80, reapproved 1988.

5) Emissions testing required pursuant to subsection (1) shall consist of

a) one test conducted during operation of the boiler between thirty percent and forty percent of maximum rated capacity; and

b) one test conducted during operation of the boiler between sixty percent and seventy percent of maximum rated capacity.

6) The rate of discharge of an air contaminant is the arithmetic mean of the test results referred to in paragraphs 5 (a) and (b).

Notice

12. Where a new boiler having a heat input capacity greater than 1.5 MJ/s and less than 50 MJ/s commences operation the owner or operator of the facility where the boiler is located shall, within 60 days of the boiler commencing operation, notify the Minister in writing of the date of commencement of the operation, the location, and heat input capacity of the boiler.

Reporting

13. 1) A report on the results of any tests conducted pursuant to section 11 shall be submitted to the Minister in writing in the format set out in Schedule III no later than sixty days after the day on which the test was completed.

2.) For the purposes of section 9, a responsible federal institution or Department set out in column II of an item of Schedule I or II, shall submit to the Minister, no later than June 1 of each year, in the form set out in schedules IV and V for each facility set out in column I of that item

a) a report indicating total NO_x emissions for the preceding period of April 1 to March 31; and

b) such further information as the Minister requests.